COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)
	) Docket No.
Preparation of the 2007 Integrated	) 06-IEP-1H
Energy Policy Report	)
	)
CEC Staff's Preliminary Retail	)
Electricity Price Forecast	)
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

MONDAY, JULY 2, 2007

9:00 A.M.

Reported by:
Peter Petty
Contract No. 150-07-002

COMMISSIONERS PRESENT

Jackalyne Pfannenstiel, Presiding Member

John L. Geesman, Associate Member

Jeffrey Byron, Commissioner

ADVISORS PRESENT

Suzanne Korosec

Gabriel Taylor

STAFF and CONSULTANTS PRESENT

Mignon Marks

Robert Logan, Consultant

ALSO PRESENT

Greg Broeking
Ken Mellor
R.W. Beck

William H. Booth, Attorney
Law Office of William H. Booth

Carl Pechman
Power Economics

Eric Wanless
Natural Resources Defense Council

Doug Snow
Southern California Edison Company

Robert Hansen
San Diego Gas and Electric Company

Mike Pretto
Silicon Valley Power
City of Santa Clara

ALSO PRESENT

Nick Zettel
Redding Electric Utility
City of Redding

Antonio Alvarez
Richard Aslin
Pacific Gas and Electric Company

I N D E X

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P R O C E E D I N G S

9:00 a.m.

PRESIDING MEMBER PFANNENSTIEL: This is an Energy Commission workshop for the Integrated Energy Policy Report. I'm Jackie Pfannenstiel; I'm the Presiding Commissioner on the IEPR Committee. To my right is Commissioner John Geesman, who is the other Commissioner on the Committee. To his right is his Advisor, Suzanne Korosec. To my left is Commissioner Jeff Byron; and to his left is his Advisor, Gabe Taylor.

With that, I have no opening comments. Do the other Commissioners? I'll turn it over to Mignon.

MS. MARKS: Good morning, everybody. Thank you so much for coming to this workshop. Just by way of orientation for those of you that are new to the Energy Commission building, restrooms are located opposite Hearing Room A, and to the left as you exit the double doors. We have a snack shop up on the second floor -- this is not an advertisement -- but we have a snack shop up on the second floor. And if you have your green badges you're allowed to walk up the central stairs and across the patio there's the snack shop.

In the event of an emergency an alarm will sound, so please follow us out the double doors, turn right through the sliding glass doors. Then walk around the building to the kitty-corner, that way, and cross into the park. And then when we get the all-clear signal we'll come back and resume our workshop.

This workshop is going to be recorded and a transcript will be docketed and become part of the Integrated Energy Policy Report record. So when you contribute to the workshop please use a microphone. And the court reporter would also appreciate receiving a copy of your business card when you speak so that the transcript will have a correct spelling of your name.

We have a sign-in sheet at the long table in the back, so please sign in if you haven't done so already.

The purpose of today's workshop is to present the preliminary electricity price forecasts. These forecasts were compiled for the three large IOUs, investor-owned utilities, and also prepared for the 13 largest publicly owned utilities in California.

I'd like to emphasize the word preliminary, in that they are preliminary forecasts because we're still having some issues with some of the forecasts for the publicly owned utilities. Not their system average price forecasts, but their retail prices for each customer class.

Following this workshop we're also then going to have a public comment period open until the 13th of July. So we would welcome your written comments on the staff draft report.

This workshop is your opportunity not only to raise questions and issues with the forecasts, themselves, but also to raise issues about the implications to California consumers, or the electricity market of these forecasts of California's electricity prices in general.

The retail electricity forecasts and issues raised by the trends that we're showing will be used in the 2005 IEPR report. The Manager of the IEPR, incidentally, is a woman named Lorraine White, although I don't see her in the audience or I would introduce her right now.

In terms of the schedule for the IEPR, in late August the IEPR Committee is planning to issue a draft of the 2007 IEPR report, as a Committee report. And the Committee will then hold hearings on this Committee report on September the 13th and 17th here in Hearing Room A.

And the full Energy Commission intends to adopt a final version of the 2007 IEPR by October the 24th.

To access additional information about IEPR-related events and publications the Energy Commission's website, front and center when you open up our website there it says IEPR right there. That provides a link to all of the IEPR notices and announcements, documents, reports, public comments -- there's Lorraine right there. They have the dockets log is there, as well as the schedule for the IEPR in general.

And if you're on the IEPR list serve you'll be noticed via email every time an IEPR workshop is noticed, or a report published.

So just wanted to make sure that you all were able to pick up a copy of each of the handouts that we prepared for this workshop. There's a final agenda. There's a copy of the staff draft report in three parts. There's the body of the report that includes appendix A. There's appendix B; and then there's appendix C. Appendix B is the one that is the data tables; and then appendix C is the one that contains the graphs of the system average and customer class charts for each of the 11 publicly owned utilities.

And the reason that the report's in pieces is that we were able to not -- to get everything copied in time for the workshop by splitting it up There's also a one-pager of system average prices, and a copy of the most important PowerPoint slides in today's presentation. As well as a copy of the article by Dr. Carl Pechman from a recent Public Policy Institute of California article called, California's Electricity Market, A Post-Crisis Progress Report.

So we budgeted three hours for today's workshop, including opportunities for public comment. The first half of the workshop Greg Broeking and I will present the preliminary retail price forecasts. Then Dr. Pechman will speak on the value of providing California's consumers with robust retail electricity price forecasts.

And then following a short break Dr. Bob Logan will discuss the relationship between forecasts of retail electricity prices and forecasts of natural gas prices, and present an estimate of the degree to which California's electric utilities and their customers are exposed to changes in natural gas prices.

Our workshop session then changes from a presentation format to a panel discussion with representatives from California's electric utilities. And Ken Mellor will pose questions to these utilities' spokesmen about what they believe are the likely drivers of retail electricity prices in their service territories, and within California, in general.

I'd like to preface the presentation of retail electricity price forecasts with a short overview of our forecast scope and methodology, and how we presented the findings.

Then I'll present our estimates of retail electricity prices from a statewide perspective.

We want to provide a ten-year forecast of retail electricity prices. And in consideration of the IEPR report's adoption in late 2007, our forecast period is 2007 to 2018.

We collected some recent historical data, as well, for context for the years 2005 and 2006.

The utilities involved in the forecasting effort were those whose peak electricity demand in 2005 was 200 megawatts or greater. That group of California electric utilities contained the three largest investor-owned utilities, Los Angeles Department of Water and Power; the Sacramento Municipal Utility District; three irrigation districts that have electric service functions, that's Modesto, Imperial and Turlock.

And then eight cities with electric departments, Anaheim, Burbank, Glendale, Pasadena, Redding, Riverside, Roseville and Santa Clara, which does business as Silicon Valley Power.

We also intended to produce retail electricity prices for direct access customers, both residential and nonresidential. But that effort didn't get completed in time for this workshop.

Last spring the staff developed draft forms and instructions for collecting data needed about the electricity costs and sales. And we conducted workshops to get feedback on those draft forms and instruction; modified the forms; and then presented them to the full Commission for adoption.

And upon Commission adoption of these forms and instructions we distributed them. And then received responses from electric utilities in various states of completeness. And when necessary we followed up with individual utilities to question the data that they submitted to us, and also to obtain more current data.

Retail prices were calculated by dividing total annual revenue requirements by total annual sales. This calculation produced system average prices for the state as a whole, and for each electric utility.

With data on total annual revenue requirements that had been allocated by the utility to each of its major customer classes, and to its annual sales forecasts for each of these customer classes, we were then able to calculate an average price for up to five customer classes per utility: residential, commercial, industrial, agricultural and other, which, for example, there's street lighting.

Not all utilities have agricultural customers, and also some utilities combine their commercial and industrial customers into one class. So we were not able to produce a California systemwide retail price calculation per customer class.

The statewide system average was calculated for the years 2005 to 2016, rather than to the year 2018 because of limitations in the reported data. We presented these prices in both nominal and real dollars, inflation-adjusted dollars, using a deflator series that set 2005 as the fixed year.

And from those two data series we were then able to determine the annual growth rates in both nominal and real terms, and the percentage change in average prices between 2005 and 2016.

And utility-specific prices were formatted in the same way. Nominal, and then inflation-adjusted to the 2005 dollars.

As we tried to emphasize in our staff report these prices are not rates. This is not a rate forecast. So that if a family or a company is considering an investment in energy efficiency and distributed generation, that's a good thing. But they would need to look at their specific rate schedules as part of the economic analysis of that specific project.

So let's look now at our California system average price estimate. The system average price forecast for California was calculated by adding together all of the total annual revenue requirements of the 16 electric utilities. And for the investor-owned utilities I'm talking about the total annual revenue requirements for just their bundled customers.

And dividing that sum by total annual electricity sales. The average is therefore weighted toward the electric utilities with the largest proportion of annual revenue requirements and sales. So it would be the three largest investor-owned utilities, and LADWP and SMUD.

The slope of the increase in retail prices nominally is fairly flat. It grows at less than 2 percent a year. And in real terms, based on our deflator series, prices are projected to decrease between 2005 and 2016 at an annual rate of 3 percent a year.

We were able to locate a California-specific retail electricity price that was published in February of this year by the U.S. Energy Information Administration. And the EIA's forecast for California's electricity prices initially are close to our results, but the differences between the two get quite significant in the later years. The biggest gap in the 2011-2013 timeframe where the difference is as much as 20 percent, they are low; their forecast for us is a lot lower.

EIA's methodology is basically the same as ours. They divide total revenue requirements by total annual sales, but they use a computer and assumptions, gross economic assumptions like gross national product.

EIA also has looked back at the accuracy of their retail price forecasts and determine that generally they're off by 17 percent. So maybe ours -- given their 17 percent fudge factor maybe ours will be fairly close.

ASSOCIATE MEMBER GEESMAN: Have we done a similar look back, ourselves?

MS. MARKS: Yes, I tried. And it's not easy for us. But generally our prices this time are higher than what we have forecasted in the past.

Another way to interpret the flat nature of our curve, top curve, is that the utilities have a good idea of what will happen over the next few years, but after that they just don't know. They don't know what transmission lines or utility-owned generation will be authorized by the Public Utilities Commission, or their governing boards or city councils. But they know that prices aren't going to go down.

So, let's look at the results for each of California's large investor-owned utilities. We will see the same pattern in their statewide average calculations.

PRESIDING MEMBER PFANNENSTIEL: Excuse me, Mignon. What you just said in terms of why we might see flattened numbers out beyond a few years, do you know that from the discussions with the utilities, that after the first couple years they're just applying a set escalation factor? I mean, how did they come up with their numbers that they gave us in the forms?

MS. MARKS: I know that some utilities decided not to put in like a transmission project because they just don't know whether it will be approved by the Public Utilities Commission. So, I think that they didn't put like large capital investments in there.

In terms of the data, yes, there were some of them that just have simple escalation factors for costs. And in our staff report we looked at some of these historical costs, at least for the investor-owned utilities, based on the data we collected from the FERC form 1, and you know, we looked at what those escalation factors were.

But I haven't gone the next step to look at what the projected numbers are and compare them to the historical. I'd like to do that in the final staff report.

PRESIDING MEMBER PFANNENSTIEL: But qualitatively -- maybe we can ask the utility panels this later, qualitatively it seems like they may have given us real estimates for the first four or five years, and then some kind of flatline projection thereafter?

MS. MARKS: I think that would be a good discussion.

PRESIDING MEMBER PFANNENSTIEL: We'll ask them.

ASSOCIATE MEMBER GEESMAN: If they decline to put in significant capital projects, particularly in the later years, is it correct then to infer that there may be an understating of their revenue requirements?

MS. MARKS: It's possible.

ASSOCIATE MEMBER GEESMAN: And that would presumably then result in a lower price projection than would otherwise be the case.

MS. MARKS: It's very much of a moving target because on the one hand you have some costs are declining. For example, the DWR contracts are expiring. But then the utilities are acquiring generation, you know, through other means. So it's just a lot of cross currents.

ASSOCIATE MEMBER GEESMAN: You said that they know prices are not going to come down. I look at your graphs and real prices do come down. In fact, that's been a feature of criticism by at least the 2005 IEPR Committee. That without some demonstrable showing as to why we should think that's the case, that may be an unrealistic assumption to be making.

So I think one of the things we're going to want to do is dig down and get a better sense as to what is it that contributes to that decline in real cost.

PRESIDING MEMBER PFANNENSTIEL: And especially since the statewide price are, as you know, driven by the few largest utilities. We probably need to probe a little bit there.

MS. MARKS: Pacific Gas and Electric's data, they sent it to us in the form of four scenarios. And we used PG&E's scenario two to calculate the California system average. And we present the prices associated with scenario two again here.

PG&E's system average prices are forecasted to grow at slightly slower annual rate than the statewide average of 1.4 percent per year. In real terms that translates to a negative 8 percent annual growth rate.

The forecast of prices by customer class you'll note reveals a little bit of changeover, shifts in revenue allocation between customer classes in the early years.

(Pause -- computer problems.)

MS. MARKS: Is there anybody more technically qualified than me to help me advance this? Oh, thank you.

(Pause.)

MS. MARKS: So Southern California Edison's system average price, this pattern shows a 1.8 percent annual growth rate nominally, and a negative 5 percent in real terms. This is the breakout by customer class. Pretty flat in later years.

It's a general pattern that residential customers are higher than commercial, than industrial at the bottom. It's a pretty common pattern across customers. Unless it's publicly owned utilities, and sometimes the small commercial rates are higher than residential.

San Diego Gas and Electric's pattern is very similar, 1.6 percent annual growth rate nominally, a negative 7 percent in real terms. SDG&E just wants to make sure that when we publish these that we put a disclaimer that cautions people this is not a rate forecast. If you're going to be making investment decisions, you know, consult real rate schedules. I'd like to now introduce -- oh, I'm sorry. And here is the pattern per class.

I now would like to introduce Greg Broeking of R.W. Beck, who was very helpful, critical in pulling together the retail price forecasts for the 13 publicly owned utilities.

MR BROEKING: Good morning. I'm going to be talking briefly about the two largest publicly owned utilities, Los Angeles Department of Water and Power and Sacramento Municipal Utility District.

As Mignon mentioned earlier we forecast 13 publicly owned utilities. And Los Angeles Department of Water and Power and SMUD comprised 83 percent of the revenue in electricity sales for all the reported publicly owned utilities. So, as you can see, they were, by far, the two largest ones; 63 percent, I'm sorry.

MR. SPEAKER: Can you speak up a little bit?

MR BROEKING: Yes. Is that better?

LADWP is the third largest electric utility in California. It has 1.4 million customers; 2.3 billion in retail sales; and 23.4 million megawatt hour sales. That's in 2005 historical data. So they're slightly above or larger than San Diego Gas and Electric.

LADWP is forecasting over the next three years, beginning in 2008, three 3 percent rate increases. The reasons for those increases are distribution system improvements. They pretty much have an aging infrastructure that needs to be improved and replaced. New energy efficiency programs that they're developing. And increasing their renewable energy through the renewable portfolio standard.

This chart shows their historical 2005 system average rate at 9.2 percent. We're forecasting that to go to 13.1 percent in 2018, which is a 42 percent increase in nominal terms. In real terms in 2018 it's going to be 9.9 cents.

The cutoff on nominal, if it's about 30 percent nominal, that means there's going to be a real increase in prices. Anything less than 30 percent in nominal terms means there's going to be a decrease in real terms.

ASSOCIATE MEMBER GEESMAN: Let me ask you on that chart, what capital improvements do you include after 2012?

MR BROEKING: I believe I used projected averages. Over the next five years they're having a very extensive capital improvement program.

ASSOCIATE MEMBER GEESMAN: Yeah, I see that on the chart.

MR BROEKING: Yeah, I think it's about 800,000 a year. And they're planning on financing -- well, their goal is to get to 20 percent rate funded improvement and 80 percent debt. Right now I think they're about 65 percent. So over the next few years they're going to try to get to the 20/80.

And I believe after 2012 I escalated 5 percent a year based on probably the previous five- or seven-year average.

ASSOCIATE MEMBER GEESMAN: So they continue with a growing capital expenditure program after 2012?

MR BROEKING: Yes. Sacramento Municipal Utility District is the fifth largest electric utility in California. It's approximately about 40 percent size of LADWP. And it has -- this is in 2005 data, also -- 573,000 customers. A little over 1 billion in retail sales; and 10.5 million megawatt hour sales of electricity.

They are planning a 7 percent increase in January 2008. Primary reasons for that increase is increased cost of natural gas, aging equipment replacement needs and increased use of renewable energy. In 2005 their system average cost was 9.8 cents. In 2018's nominal terms we're forecasting it to be 12.3 percent, around 25 percent increase in nominal terms. In real terms in 2018 that would be a decrease to 9.3 cents from the 2005 amount of 9.8 cents.

Are there any questions? Thank you very much.

MS. MARKS: Would anybody like to make any public comments about the forecasts in general? Not just Greg's presentation or my presentation, but just have some initial feelings about the prices.

Well, okay, then.

I'd like to introduce now -- oh, good.

MR. BOOTH: William Booth; I'm a regulatory attorney and I work at the --

PRESIDING MEMBER PFANNENSTIEL: Bill, you need to go to the mike so we can record --

MR. BOOTH: William Booth; I'm a regulatory attorney. I practice at the PUC and I represent large industrial customers of Edison and PG&E.

One of the reactions I had to your numbers are did you simply ask utilities for their projections of their revenue requirements in these out years beyond 2007.

MS. MARKS: Yes, we did.

MR. BOOTH: And having received those, did you engage in any dialogue with them as to the basis for those revenue requirement estimates?

MS. MARKS: I believe we did. Nancy, you worked with Southern California Edison. Did you -- I know that we had some questions about their revenue allocations by customer class.

MS. TRONAAS: Are you asking what was built into those projections?

MR. BOOTH: Exactly. You know, the idea that in real terms prices, system average prices are trending down over this period is good news. But I dare not go there. I'm concerned about it.

Because we are about, in California, changing the resource mix for these utilities. We're going to get rid of coal; we're going to get rid of some of the less expensive resource facilities that we might have. And that has to have, it seems to me, some upward impact.

We're going to have to spend a lot of money, as Mr. Geesman has indicated, on big transmission lines to access new resources.

And I wonder whether this discussion or

this report might be more illuminating if we had some analysis of that. Obviously it's conjecture, but we can begin thinking about what's going to happen to that.

MS. MARKS: Points well made, thank you.

ASSOCIATE MEMBER GEESMAN: Let me rephrase his question. Did we adjust the utility-provided revenue requirements?

MS. MARKS: We did not for the investor-owned utilities. We did for the publicly owned utilities.

ASSOCIATE MEMBER GEESMAN: Have you ever seen a projection from the investor-owned utilities that did not have declining real prices?

MS. MARKS: In my personal experience --

ASSOCIATE MEMBER GEESMAN: Yes.

MS. MARKS: -- no.

ASSOCIATE MEMBER GEESMAN: Have you ever seen a ten-year period of time that did not have steady or increasing real prices?

MS. MARKS: Real prices. I'm going to have to defer to the economists in the room.

ASSOCIATE MEMBER GEESMAN: Did you do a historical analysis to determine if there had been any ten-year period of time where California had experienced steady or declining real prices?

PRESIDING MEMBER PFANNENSTIEL: Since 1950.

MS. MARKS: Me, personally, no, I did not.

ASSOCIATE MEMBER GEESMAN: Did anybody else on the staff?

MS. MARKS: No.

ASSOCIATE MEMBER GEESMAN: That's one of the problems I have with this process. I raised it in 2005. I'm going to raise it again in 2007. If all we're doing is republishing utility-provided projections, of course everything is going to look wonderful. It always does.

But reality seldom seems to turn out that way. And I challenge any of the utilities to come up and explain to me why that's a misstatement on my part.

PRESIDING MEMBER PFANNENSTIEL: We will have an opportunity, won't we, to talk with each of the utilities and try to determine how credible their out-year forecasts seem to be?

MS. MARKS: I think we have that opportunity right now if anybody would like to comment.

PRESIDING MEMBER PFANNENSTIEL: We have a panel coming up, though, --

MS. MARKS: Yes, we do have a panel --

PRESIDING MEMBER PFANNENSTIEL: -- as I understand it.

MS. MARKS: -- discussion, as well, on cost drivers.

All right. I'd like to now introduce Dr. Carl Pechman, who I found out about by reading a copy of his report on -- a post-crisis progress report that was published in the Public Policy Institute of California. It provides a very nice summary of things done since the energy crisis including the loading order and the renewable portfolio standard.

Also, the thing that intrigued me in his article is that he mentions how nice it would be if California were to produce retail electricity price forecasts. So I thought it would be nice for me to connect with him, since that's what we're trying to do here.

So, Dr. Pechman.

DR. PECHMAN: Thank you, Mignon, and thank you, Commissioners, and everybody else. It's a pleasure being here.

Let me just try to demonstrate my technical capability by plugging my computer in for a second.

(Pause.)

DR. PECHMAN: It doesn't seem to fit. I apologize; I'm going to read off my slides. There are no graphs. They were for convenience. I'd be happy to provide them afterwards.

So let me just give you a little about my background while I'm booting up here. I'm an economist. I've spent close to 20 years at the New York Public Service Commission. Moved to California in '97. Reason was my wife got a position teaching at UC Santa Cruz.

And since then I've been working as a consultant on a number of issues, continuation of my work in New York on market design. I was one of the people at the New York Commission responsible for overseeing the design of the New York ISO.

Also in New York I was responsible for avoided cost forecasting over a long period of time. And so have some hands-on knowledge with respect to methods of forecasts and prices and things of that sort.

And I've long been an advocate of the importance of price forecasts. And some work that I've been doing lately in Santa Cruz has reiterated the importance -- let me know if you can't hear me, I'm not standing too close to the microphone, but.

Some work that I've been in Santa Cruz has reiterated the importance of price forecasts for me, and specifically that is the working with the local school board on making the decision about what kind of investments to make in solar. And I'm doing that on a pro bono basis.

Many of the members of the school board, you know, are my neighbors and friends, and have been coaches. And anybody who knows my athletic prowess is happy to know that I have not been a coach. But I do know a little bit about electricity and power purchase agreements and contracts. And have spent many years litigating a whole variety of contracts, both commercially, the contracts that I was a witness for the California parties in litigation on the long-term contracts. I've been involved in lots of other litigation related to the California energy crisis, including work with respect to Enron's gaming behavior.

So, I believe it's very important to look at the future and try to change the way we've done business. The paper that I wrote for the Public Policy Institute that you have describes the way in which I think California is moving. And I think it's moving in many positive directions.

But one of the ways in which California is moving, in particular with respect to the solar program, is shifting in investment decision to customers. And in particular there are many customers out there who are now making very significant investment decisions on putting solar photovoltaics on their facilities, either in their homes, on schools, factories, hospitals, whatever.

And the economics of photovoltaics is largely driven by three things. It's driven by state subsidies, tax subsidies and expected future prices. And it's the expected future prices that I'm going to talk about.

The primary vehicle -- there are essentially two different ways of doing a photovoltaic investment. One is to self-fund that investment. And that's fairly straightforward. You make the investment decision. You either do debt or equity or home financing to pay for your solar investment.

A second alternative, which is becoming very popular, is called a purchase power agreement, in which the host site provides basically the roof space for a third party to invest in the solar equipment that's put on the roof. And in exchange, the host buys back the power that's produced by that solar facility.

There are contract terms that you have to get involved in in any kind of contract. But what I want to do is focus specifically on the pricing terms for that. Because from the standpoint of the school board listening to lots of public input, there are basically two schools of thought.

One school of thought is solar is good; it's good, then let's do it. I don't particularly subscribe to that school of thought. I subscribe to the school of thought that a school board has a fiduciary responsibility and an obligation to its students. And that to the extent that the expected price of solar is any higher than it would be under retail rates, the school board ought not proceed and do solar.

And happily for me the Santa Cruz School Board has adopted basically my approach towards solar. And, as you know, all school boards, or at least in Santa Cruz, the school board is strapped for cash. And so the idea of going out and doing good things, while good and wonderful, really can harm the ability to achieve the primary purpose of the schools, which is to educate.

So, the Santa Cruz City School Board was in the process of entering into a power purchase agreement with a company called Generating Assets. They came to Santa Cruz and said, look, we'll make you at least as good off, as well off. And the reason that you'll be at least as well off is that we're going to take your current retail price and we are going to escalate that current retail price 3 percent a year for the next 20 years.

And you'll be better off, because if you look at the historic escalation of retail prices for the last 10 or 15 years in the electric utility sector for PG&E, that's been close to 5 percent. So you'll be saving that 2 percent growth. And boy, over 20 years that's going to become quite a big gap. And you, the school district, are going to save lots of money.

I looked at some of the earlier forecasts done by the California Energy Commission and I said I think that there's a problem here. The body that's responsible for forecasting has a totally different view of what the future is going to be than the people who are selling you these solar facilities. And that it's not clear to me that this is a great deal.

Got involved in sort of renegotiating and trying to create some competition among solar providers. We were able to knock the price down. And I'll just read you the current price offer that we have, which is 11.96 cents a kilowatt hour, with a price escalation of 3 percent per year.

So that seems to give a 7 percent discount -- rates to the school board. And the school board's interested in that. And one of the things that is also attractive about this is that many of these purchase power agreements, after five or six years when the tax benefits disappear have buy-out provisions.

So, if you're looking at solar from a school board's perspective, actually given the current financing the least expensive way to do it from the school board's perspective is enter into a purchase power agreement for a number of years where hopefully the tax benefits and incentives are captured in those first few years. And you can get a buy-out price which is maybe 40 percent of the initial cost of the facility in year six or seven or so. And then finance that with tax-exempt debt. And the effect is to have a lower stream of prices that you would have for your electricity produced by your solar photovoltaic.

But the problem is -- or my problem, as somebody in the energy community trying to assist the school board is, that there is no place for me to go and say, what is a good forecast, what's not a good forecast.

The school board can't afford for me to go out and use a production-costing model and run a bunch of scenarios for them. These projects have very thin margins to begin with. School boards don't have that kind of money to be entering into that kind of expert analysis.

So the bottomline is, I think, that customers need more information. And I understand that the focus of this report is really as a driver -- of your report really is a driver for demand forecast and the energy plan.

But I would like to encourage -- and earlier this morning we've heard that the forecasts are not for investment decisions. But the reality is that the one place customers have to look for future price forecasts that are presumably objective forecasts, is to the Energy Commission.

And I would encourage you to consider making a more robust forecast, not necessarily as part of the IEPR process, but possibly as a followup process, to not hold it up.

Where investors, school boards, hospitals, industrials are able to really get a sense of the effect of various inputs on the load forecasts, how the assumptions affect prices.

And to do so what I would recommend is to begin with is to break down the price into its two primary components. Components related to capital recovery and components related to energy prices. So that assumptions on changing investment and return on capital can be evaluated by school boards or others to get a sense of how prices might change over time.

If we, five years from now, run into a

period of high inflation, you can show that in a forecasting type of mode by reflecting that in the rates of return, which are allowing utility capital, which would drive the return on and of capital that utilities receive in their rates.

So, with respect to capital recovery, the level of investment is important, and the cost of capital is important. With respect to energy prices, there are a whole variety of issues that are important, including natural gas, which is critical.

But also I think one of the reasons the forecasts have been wrong in the past have been the problems of scarcity -- and the exercise of market power. Depending on who you talk to, if you're talking to Bill Hogan, there is no exercise of market power. I believe that -- and that all prices in the energy crisis can be described by scarcity -- I believe that there was an exercise of market power during the crisis. And I believe that that can happen again, but not to the same extent.

So, vulnerability to scarcity pricing and market power is important in terms of future prices.

Customers are looking at solar as a hedge against what happened in the energy crisis. Explicitly, we don't want to go through that again. We're going to invest in solar that will insulate us.

So, some idea of the probability of that happening again in terms of prices is important. the ISO has certainly taken many steps in terms of market design with mitigation approaches that will limit the ability to exercise market power.

In addition, the Federal Energy Regulatory Commission has also implemented new structures that will hopefully keep those kinds of price excursions from happening again.

Just very quickly there are three other areas which I think will affect energy prices that are important for customers to understand, at least at a preliminary level. Those all involve activities which are ongoing in the regulatory agencies of the state. And those include renewable energy credits, greenhouse gas costs and capacity markets.

So those are three areas that when you're talking to a school board, and even when you're talking to investors in solar, solar developers, you kind of have this like blank look like what is that. And it would be useful to have some sort of dialogue on the part of the Energy Commission saying at least what these factors are, how they might affect rates. And also whether or not they would affect rates that would be used by customers with respect to solar investment.

In conclusion, I think a range of forecasts will facilitate customer decisionmaking and help the state achieve its solar objectives. I think it's important to have a sense of the kinds of information that customers need, and perhaps to outreach to customers, to find out what kind of information that they need.

And enough information to provide customers with information to judge the impact of various inputs on price forecasts. Customers can make their own decisions on how to weigh the future price of natural gas, the future ability to exercise market power. But if there's a matrix or something that will allow them to put their own probabilities on different components of price, I think that will be worthwhile.

Also I think it's important to describe the nature -- and this may again not be the appropriate forum for this, but to describe the nature of rate options and how those options will affect things like photovoltaic investment.

One of the problems that we have looking at the investment from the standpoint of the school district is that they're on one rate class right now, and we're looking at -- although the PUC has slowed up this effort so it's not an immediate issue -- but we're looking at going to time of, you know, to real-time pricing, time-of-use rates, changing rate classes from A10 to A6.

So, it's very important to have some sense of how that change of rate classes will affect customer investment decisions.

And ultimately, in terms of my wish list for customers, it would be to actually provide some analytical tools that customers can use for themselves.

Now, I thank you for your time, and hope that these comments have been useful.

PRESIDING MEMBER PFANNENSTIEL: Thank you, Dr. Pechman. I think they were very useful. I would note that what you just laid out was, in fact, a description of the very complexity that we're facing in trying to provide that kind of rate information.

Because even if we got all the capital costs correct and even if we had the fuel costs at a level that we could play around with those, you still have the very real problem of allocation to rate classes. And the decision going forward of how the PUC will ultimately allocate among residential class and school districts, for example, whether they're on special rates.

So that then, you know, even if we had the averages right that last step may throw off the investment decision.

But thank you for bringing those perspectives.

DR. PECHMAN: Thank you.

MS. MARKS: Would you like us to continue on with the program or should we take a short break?

PRESIDING MEMBER PFANNENSTIEL: I think it's early enough we can probably continue.

MS. MARKS: Okay, very good. I'd like to now introduce Bob Logan, who has been consulting to us on this retail price forecast in the area of natural gas price sensitivity to changes in natural gas prices.

DR. LOGAN: Good morning. I'd like to start by just giving a little history. There are two parts to this that I'd like to point out.

The first is the variation that we've experienced in California and the prices that have been paid for natural gas by electric generators. For example, we see here just two years, the price went from about $3 to about $9, or basically tripled in a two-year period. Then we see it comes back down to around $4. And in the space of three years, doubles to $8.

So there have been rather dramatic swings in the price of natural gas paid by California electricity generators.

There's one other fact on this chart that I'd like to bring your attention to, and that's back here in the period in the late '90s. And here you can see that for these three years the average price paid for natural gas by electric generators was $3 or less.

And the reason I want to bring your attention to this is when we get to a later slide where we start talking about the cost of natural gas, I want to remind you that back in this time period just about seven years ago, costs were in all likelihood below $3. Since we had a period of time, it was a fairly long period of time, where the price paid was under $3. And, of course, now we're seeing much higher prices.

Here we have a historical graph showing system average prices paid by California electricity consumers. And the purpose of this slide is to note the difference in the variability. The high variance you saw on the previous chart does not translate into wild swings, wide swings in the retail rate.

There are several reasons for this. Regulators and the boards of publicly owned utilities have mechanisms to smooth out the natural gas spikes; they're able to borrow short term and not recover the full amount in a given year.

And also natural gas is not a hundred percent of the cost of providing electricity. So even though the price of natural gas to the electric utility may double, that doesn't mean all of its costs have doubled, and therefore the retail price isn't going to double.

Here we have, as you can see on the bottom, a Energy Information Administration, Department of Energy agency, that provides annually forecasts of all kinds of natural gas prices.

We selected the natural gas price forecast for electricity generators. And as you can see, in 2005 nationwide the price was about $8.50; came down to about $7.50 last year.

Now, I'd like to make an important point here that I'll come back to. These are prices, not costs. And there's a big difference between the price paid and the cost of actually developing and producing natural gas.

The cost would be down here in the $4 to $5 range; it might be here in the $5 to $6 range. It may be in the $6 to $7 range. These are the prices. So let's focus on the prices for a minute and I'll come back to the costs.

As you can see, the EIA forecast has a slight increase for a few years, and then in nominal terms, the price falls continuously through to about 2013. So what you have is a drop from $8.50 in 2005 to about $6.75 or so in 2013.

Since these are in real 2005 dollars, what you're also getting is the real price dropping from $8.50 to about 5.5 in this area here, maybe a little bit more than that.

So, you're getting the natural gas price forecasted by the Energy Information Administration dropping by one-third. And as you've already heard earlier today and have asked questions about, what are some of the causes that are causing the retail price to go down in real terms.

Well, one of the causes is that the cost or the price of natural gas is projected to fall by a third in real terms. And we'll get a little bit more into just how reasonable that might be. After 2013 we start to see an increase.

I'm going to come back to this chart, but before I leave I would like to point out to you one possible logic behind this type chart. If, in fact, cost of production, the marginal cost of production is in this area here, in the $5.25 or $5 range, you could draw a line that would basically show an annual increase in that cost until you get to 2013, and then cost and price join together. And then the two continue on after that.

And therefore, the logic behind this could be that cost in 2005 was in the $5 range;

everything between 5 and 8.50 is a premium of some kind. For example, we know that the difference between 8.50 and 7.something is partially a hurricane premium. 2005 was when the two devastating hurricanes caused gas supplies to drop, and part of this price does have a hurricane premium in it.

So, to a certain extent the logic here might be that there is this premium, and that this premium is going to go away. And that costs will increase and the two will finally come together. That gives you this logic of real price of natural gas electricity generators falling by a third.

I'd like to make a few comments about the shape of this forecast. Every single utility has, in the natural gas price forecast that they submitted to this Commission, this pattern. Every single utility that provided a forecast over the forecast period has the exact same logical pattern. That there will be falling nominal natural gas prices followed by rising natural gas prices. That there will be falling real natural gas prices.

So, this is the world view. And it all lines up with the Energy Administration annual energy outlook forecast as presented.

So, let's move on --

ASSOCIATE MEMBER GEESMAN: Bob, let me ask you, --

DR. LOGAN: Sure.

ASSOCIATE MEMBER GEESMAN: -- went back to the period early to mid 1980s and projected that out ten years to the early to mid 1990s. My supposition is that you'd see a similar decline in real natural gas prices and in nominal natural gas prices. Does that check out with your recall, as well?

DR. LOGAN: Well, if you go back to the early '80s you'll find a very dramatic drop in oil prices; early '80s you actually had the real historical high in oil prices. To a certain extent natural gas follows that, but not as dramatically.

ASSOCIATE MEMBER GEESMAN: Is the slope, and I suspect when you get it from EIA data, whether the historical ten-year decline from early '80s to early '90s, or mid '80s to mid '90s, was close to or perhaps even identical to these projections. Is that type of information available to us?

DR. LOGAN: I'm not sure we can get all the way back to the 1980s, but we have at least 10 or 15 years worth of EIA forecasts that we could put together for you. And we'd be happy to do that if you like.

ASSOCIATE MEMBER GEESMAN: I think you should. I mean this is a pretty happy projection; and that earlier ten-year period was a pretty happy time, at least if you weren't in the business of selling natural gas. And I'd like to have some sense as to whether there is sufficient justification to think that kind of experience is in front of us again.

DR. LOGAN: We'd be happy to do that for you.

COMMISSIONER BYRON: Dr. Logan.

DR. LOGAN: Yes.

COMMISSIONER BYRON: My recollection is that the staff did look back that last five or six EIA energy outlooks. And that was either for electricity costs -- I'm sorry, electricity price projections or natural gas. And my recollection, as well, was that every one of those five or six EIA projections the last five or six years significantly underpredicted where we'd be today.

Is that your recollection?

DR. LOGAN: Yes. What appears to have happened is that many of the forecasters and people in the industry are reliving what happened in the early '80s when prices fell. And so whenever prices rise, they always seem to be projecting this pattern of a falling price.

They're just, it happened in the early '80s, it's going to happen again.

ASSOCIATE MEMBER GEESMAN: This is the morning-in-America phenomenon.

DR. LOGAN: Yeah, also known as the Maginot Line. The Germans are just going to come through the same path again. They're fighting the last war over and over kind of event.

But, yes, that does seem to be the current pattern.

Here I am showing a slide that was shown to you in the natural gas workshop. This particular slide, which appeared first in the National Petroleum Council 1993 report, is actually produced for them by a consulting firm called IHS. The firm basically has all of the industry as their client, and has access to databases that no other firm has.

The importance of this particular slide is to show the geological imperative, if you will, or the geological forces that are driving natural gas costs.

What you see here is back in 1980 a typical well would have all of this area, represented by this light blue color, as its production. In other words, you would drill the well in 1980; you'd have a fall-off in production, but it would just keep on producing at very good volumes. And is still producing today.

This would be your conventional well in Texas or just off the shore in the Gulf of Mexico where you just stuck a pipe in the ground and the gas just started flowing.

But then over time the amount that you got in the first year and the amount that you recovered over time fell. And it started falling rather dramatically. And as a consequence the cost, this geological fact, doubles periodically.

For example, if for every $100 of cost you have in your well, you're getting 50 million Btus of gas, well, then your cost is $2. When that falls to 25 million Btus it goes to $4. 12.5 it goes to 8. And, of course, the $100 doesn't stay $100 over time.

So, you have two forces. You have the cost of owning and operating a well going up; and you have the amount of natural gas you're recovering from the well is declining every year.

Now, it just so happens that last week IHS updated all this information. And so I'd like to read these two short sentences out of the release that they issued last week updating this information.

First, IHS says that: The trends of declining well productivity and reserves for well observed over the past few years are expected to continue to 2015." So, having done an exhaustive study, and if you want I could bore you with all the details of how many basins, et cetera, they studied, but the trend is still in place. This is going to continue.

And one of their conclusions that they reach is the most significant driver of the rise in the cost to produce gas has been, and will continue to be, declining production on a per-well basis. And it's just simple math, as I just explained to you. You get less and less gas per well; then the cost per million Btu has to go up.

And that is, you know, part of what we've been seeing historically.

So, given that, I'd like to show you this next slide which, again, you've already seen again in the natural gas workshop. And this was put together by R.W. Beck and was part of the slides that they presented.

And what this is, is -- the red is the staff preliminary forecast. All of the other forecasts are for 2015 and 2025, what all of these consulting firms and the United States Government, through it's Department of Energy EIA, are forecasting will be the price in 2006 dollars. The grey bar, the solid bar is in 2015. And then the herringbone bar is for 2025.

There is some variation in 2015 between 5.25, let's say, and 6.25. So there's maybe a dollar spread. But what I want you to come away from this is there's not a single consulting firm, nor the government, nor the federal government, nor has the staff found any state, international agency, there's no forecast that we've -- the staff has been able to find, that any of the consultants have been able to find that doesn't basically say the costs aren't going anywhere in real terms.

If we go back to this chart they're basically saying that if in this time periods, 2005/2006, you're in this box, so to speak, between $5 and $6 and you never leave it. Which is consistent with this graph, with this forecast. That the real price -- that the price is going to meet cost.

So, every single forecaster is coming up with this result. That doesn't necessarily mean they're right, because I know for a fact that they're not all getting there by the same path. There's not a single unified theory.

One consulting firm will have United States, for example, generating an enormous amount of electricity with coal, so that there's not as much demand for natural gas and that keeps the price down.

Another firm has both the McKenzie pipeline and the North Slope pipeline coming in on the old schedules, flooding North America with arctic gas, keeping the price down. Another firm has the world being flooded with LNG. Again, a way to keep the price down.

But they still all come in at this

logic. So, in terms of what you actually see in the utility price forecast, to a certain extent they are all driven by this underlying decline in real natural gas prices as forecasted by this entire government-consulting forecasting complex.

So what we come to is the payoff slide. And here we see an estimate of the dependency of each of the major utilities in California, the five largest utilities, on natural gas. And how much of their retail rates, at most, are affected.

Now, one of the things that I hope you notice is we've got the pattern back, the same pattern that we saw on the EIA natural gas price forecast, and the same pattern that I told you every single utility's natural gas price forecast has. You have this decline into the mid-teens or the 2000s, followed by a movement back up again.

To a certain extent the dependency declines because they forecast natural gas prices decline. So they may be using just as many million Btus, but to the extent that the price falls, the sensitivity of your retail rate will fall. Because the cost falls. It's simple math. The decline each day is the same, but the price falls, then the total revenue required to pay for it goes down.

So, part of what you're seeing here is that same logic being repeated. The same drop in retail and nominal cost of natural gas causing the sensitivity at the retail rate to decline during this time period.

And this is part of the reason why these forecasts of retail rates have a falling real forecast is this driver of natural gas.

PRESIDING MEMBER PFANNENSTIEL: Bob, where did these numbers come from? I mean this is -- there are a lot of different ways that you can see these patterns. You could see them either because of using less natural gas, or they're using the same amount of natural gas, but it's cheaper. Or the rest of their revenue requirement goes up faster than the fuel part of their revenue requirement goes up, since this is a calculation involving all three of those and maybe more.

DR. LOGAN: Well, I did the calculation; I prepared this. To a certain extent I can tell you that -- well, I can tell you absolutely that it is because of the natural gas prices falling. Because -- and to sort of tie this into the scenario work, this would be a kind of business-as-usual case. This would be one of your lower numbered cases.

PRESIDING MEMBER PFANNENSTIEL: So, just help me with the RPS, then. What does it assume for the RPS that everybody makes the RPS targets?

DR. LOGAN: Well, we didn't have enough information. This is coming off of what they filed for their electric price forecasts. And that -- but we will be happy to look into that and try to get back to you on that to see how it matches up to their submitted resource plans.

PRESIDING MEMBER PFANNENSTIEL: Great.

DR. LOGAN: What you basically see is that SMUD is the most dependent on natural gas. Now, as we point out in the report, though, SMUD appears to have a plan to eliminate the retail rate from being exposed to changes in natural gas prices. And that is to purchase natural gas reserves; and therefore change natural gas from a variable cost to a fixed cost.

And so it would, in essence, eliminate their sensitivity to natural gas prices, to the extent that they've purchased enough reserves to cover their needs.

LADWP is also potentially, or may

already have gotten involved in a similar type program.

For the three IOUs you see that they start out in the neighborhood of 30 percent, and over time move down. Again, to a large extent, reflecting the drop in natural gas prices; but to a certain extent, reflecting a change in -- mostly, let's just stick to the drop in natural gas prices.

ASSOCIATE MEMBER GEESMAN: Why the extraordinary difference between San Diego and Edison which seems to occur next year.

DR. LOGAN: I knew that -- and I apologize that I don't have that in my memory right now. But I will look it up again and get back to you.

ASSOCIATE MEMBER GEESMAN: Appreciate that.

DR. LOGAN: Sure.

COMMISSIONER BYRON: Dr. Logan, it also seems, though, this figure, as helpful as it is, may be masking the potential train wreck that we're facing here if, indeed, all the prognosticators all point the same direction on the price of natural gas are incorrect. This figure kind of reflects that same downward trend.

DR. LOGAN: Exactly. And if we go back to this slide, I think one of the problems is that no one knows where the marginal cost of producing natural gas is. And if, in fact, it's right around $7, which is possible, then the forecast really should look like that. In other words, it should start a 7 and it should just increase.

Because from this slide we know that wherever you are, whatever the current cost is, it's going to increase. It's just a geological certainty. It can't be avoided.

So, wherever you are here, like I'm saying, if you're at $7 then it just would increase this way and go up to 8, 9 and eventually up to 14.

And when you look behind the curtain and try to find out where all those forecasts that I showed you on the other slide are basing their judgment that it's more likely the cost of production is down here around $5, it's really judgment. You're not really going to find any documentation where they're going to show you the marginal well and what it costs to own and operate, and what kind of production you're getting out of it.

And to a certain extent, if you recall, as you remember that in the late '90s the price of natural gas was under $3. So the cost would have been in the 2.50, 2.75 range. Which is below here, below the $3 line.

To a certain extent it could be that all these forecasters just don't believe it could have gone up any faster than that. That in seven years for it to have doubled is about as high as it could have gone. But, in fact, the geology moves on regardless of what we can absorb. And the fact that we're moving from all those stick-a-pipe-in-the-ground and sand, and out pours as much natural gas as you can handle, to having to fracture coal bed methane beds in order to extract just a small amount of natural gas per well, tight shales, tight sands, very hard rock with very small production.

And as that mix keeps changing it could very well be that the marginal cost of production is much closer to $7. And we'll find out in the next couple of years. Because if they're right, prices will fall, presumably as these premiums go away. And if they're wrong, the prices are going to fall because costs are much higher, and we'll see ever-increasing natural gas costs.

But the bottomline is all the forecasters are saying that the real price of natural gas is going to fall by a third. Natural gas is a significant cost component of retail rates. The fact that all the forecasts say that it's going to fall in real terms by a third; it's going to bleed into your retail electric rate price forecast. And it's going to be a contributing factor to why that forecast declined.

COMMISSIONER BYRON: Excuse me. Commissioner Geesman identifying that potential anomaly there between Southern California Edison and San Diego Gas and Electric at 2008, I also note on the SDG&E plot a projected retail electricity prices in the report there's a big anomaly, if you will, between '07 and '08 in the report, as well.

And I wonder if there's a relationship there. Commissioner Geesman probably caught that one too, but it really -- it raises some questions about what's going on there.

DR. LOGAN: And we'll definitely look into both of those and get back to you.

PRESIDING MEMBER PFANNENSTIEL: Do you have any perception of why all of the gas forecasts look so much alike given the geological trends that you're showing? Obviously everybody sees them. I'm just wondering how much people are looking at each other's forecasts and not necessarily being quite as independent.

I'm really looking at your next slide of the bars -- I'm sorry, the one after that -- that one. They're all so similar. And are they done that independently? Or are they kind of building on the same -- on each other's underlying assumptions?

DR. LOGAN: I can't read their minds, but I do think that a part of it is what happened in the '80s when a very large premium was revealed to exist between the price of oil and the cost of oil, when we dropped from $80 a barrel to essentially $10, $15 a barrel.

And I think that this has become part of the folk lore or the culture of these forecasters, that there is this premium built in. And so that's, I think, a possible explanation.

The other explanation is they just truly believe that this is what it costs to produce natural gas, and it's not going to change for some reason.

But, yes, they all go to the same conventions and talk to each other, so --

PRESIDING MEMBER PFANNENSTIEL: Right. Thanks.

DR. LOGAN: -- they compare notes.

MS. MARKS: Thank you, Bob.

DR. LOGAN: Sure.

MS. MARKS: We have a person that would like to make a comment, a caller-inner. His name is Eric Wanless from NRDC.

(Pause.)

MS. MARKS: Eric Wanless.

MR. WANLESS: Yeah.

MS. MARKS: Hi.

MR. WANLESS: Hi. Can you guys hear me?

MS. MARKS: Yes, please speak.

MR. WANLESS: Yeah, I actually had a comment earlier and I'm not sure if this is the best spot or not. But I guess I'll just go ahead and make it, if that's all right.

MS. MARKS: It is.

MR. WANLESS: We brought this up in one of the initial workshops with forms and instructions. And basically the comments I'd like to make is to the extent possible it would be, I think, really valuable as part of these forecasts to try and get at an average bill forecast, as well.

And I know that, you know, there's a lot of things going on in terms of the different, you know, rates that are bill classes and that sort of thing. But I think to the extent that the forecast will provide a meaningful output for consumers and for organizations working in the electric sector, especially with the deficiency that's having an average bill forecast for, maybe, you know, a couple different classes of customers would be helpful.

That's what I'd like to say. Thanks.

MS. MARKS: Residential and who is your next favorite?

MR. WANLESS: I would say, you know, maybe just standard residential, and then, you know, I know it's complicated, but based on possible commercial and industrial, as well.

MS. MARKS: Demand billed or not demand billed?

MR. WANLESS: Just I guess for the

residential not demand bills, but I think any information that can be added in in terms of giving people a complete picture of what they're, you know, actually paying -- what they're going to be paying in terms of decreasing penetration of energy efficiency, would be helpful.

I'm not sure how easy that will be to incorporate all the demand charges and all that sort of thing, --

MS. MARKS: Right.

MR. WANLESS: -- but I think if it is possible, that would be helpful.

MS. MARKS: Thank you.

All right. Could we take a quick break now? Ten minutes, and then we'll have our panel discussion.

(Brief recess.)

MS. MARKS: Before we begin I'd just like to mention that we are going to have copies of the presentations up on the Commission's website for our workshop, after this -- after our workshop ends.

I'd like to now introduce Ken Mellor who is with R.W. Beck. We've brought him out of retirement to help us with this. He actually has been involved with our retail price forecast work since the beginning of our project this year. Ken. Thank you.

MR. MELLOR: Thank you. Good morning. What I'm going to do is have the panel members just very briefly introduce themselves, what company they're from, and their position in the company. And then we'll get directly into the questions.

And as just a matter of procedure, even though I'm in a moderator position, I think it's going to be a lot easier if we allow Commissioners to direct questions to the individuals, as they like, rather than to try to go through the moderator.

If I can start then with Doug and just go around the table.

MR. SNOW: Good morning. My name is Doug Snow; I'm Manager of Revenue Requirements for Southern California Edison Company. I've been in that area for about 14 years. Before that I was with a utility in Texas, also in the regulatory area, for another 11 years.

MR. HANSEN: Good morning. Bob Hansen with San Diego Gas and Electric. I'm the Electric

Rate Design Manager; and I've been in that position for about 14 years in total. I'm responsible for coordinating the data that was supplied to the -- or put to the CEC.

MR. PRETTO: My name is Mike Pretto; I'm with the City of Santa Clara, Silicon Valley Power. My title is Division Manager of Market Analysis and Pricing.

In prior lives I spent 20 years at Pacific Gas and Electric Company in the rate and regulatory area. And ten years consulting in the same kinds of areas to other -- to many different kinds of clients. And the last ten years at the City of Santa Clara.

MR. ZETTEL: My name's Nick Zettel with the City of Redding Electric Utility; I'm a Resource Planner. I've been with the utility for about five years. Prior to that I was with the California Department of Transportation in project management.

MR. ALVAREZ: Antonio Alvarez from PG&E. I'm in the generation planning organization for electric procurement. And I've been there for a long time.

MR. ASLIN: My name is Richard Aslin and

I work for Pacific Gas and Electric Company; and I work in the Operations and Revenue Requirements Department. And Antonio and I kind of teamed up and did the generation-related inputs on the forms. And I did help coordinate most of the non-generation-related inputs.

MR. MELLOR: Okay, thank you. We'll get to the first question. You've already had a substantial discussion from Dr. Logan with respect to natural gas prices, so this question now is to the utilities who provided the information for the forecasts.

How are you forecasting natural gas for electricity price forecasts? And how are you integrating that cost information in your price projections?

And of particular interest, is your impression -- how do you view the relative importance of gas costs in your electricity price projection?

Let's start with Doug.

MR. SNOW: For Edison about 50 percent of our procurement portfolio is kind of driven on natural gas, so it is very important. I don't know if we can go back to the slide that shows our system average rate -- just to give you an idea of the impact of 2006/2007 was. Because we were coming out of the hurricane season, 2005, when Rita and Katrina hit, and gas prices were forecasted to be extremely high.

We built our rate levels to include those high gas prices. And then what happened was gas prices didn't materialize to be that big and the forecast for '07 was lower. As well as we had over-collections in '06 because we did put in rates based on a high gas price forecast.

So just that difference right there is driven by natural gas prices. So it is a big impact.

ASSOCIATE MEMBER GEESMAN: Anybody other than this Commission ask you to make a ten-year projection of natural gas prices?

MR. SNOW: Not that I'm aware of.

ASSOCIATE MEMBER GEESMAN: So you're not aware of anything else that is published with Edison's name attached to it in terms of a fuel price projection?

MR. SNOW: Again, not that I'm aware of, no.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: Bob.

MR. HANSEN: For SDG&E I think our gas price forecast is consistent with what was presented earlier today, the world view of the gas price shape. And so that is very consistent with our shape, also.

I know there was a question earlier of how the 2007/2008 relationship changed and why it looked the way it did. And I think it is related more to the revenue requirement side.

We're anticipating substantial increases in other costs and generation costs in total in 2008. So the proportion of gas costs to that total is much smaller. That's really due to total revenues being -- denominator.

ASSOCIATE MEMBER GEESMAN: And are you aware of whether or not anybody other than this Commission asked you for a ten-year price projection?

MR. HANSEN: No, I'm not aware of any.

PRESIDING MEMBER PFANNENSTIEL: Do you do your own natural gas price forecast? Do you buy it from a consultant? Or where does it come from?

MR. HANSEN: I believe our forecast is a

combination of third-party sources; some public, some private consultants, a combination.

MR. SNOW: Same with Edison.

MR. MELLOR: Mike.

MR. PRETTO: Well, Santa Clara's gas price forecast is based upon our contract prices of gas. We have a couple of long-term agreements with fixed prices in them.

And then to the extent we don't have our gas position covered, I use the -- I started with NYMEX and used the NYMEX projection with a zero basis to California as an indicator of future prices because that represented prices, at least at the time the forecast was made, that you could actually lock into.

And then after the NYMEX, after about 2011 or '12, the basic assumption I made is that gas prices would go up with inflation. In our forecast it was 2.5 percent a year.

ASSOCIATE MEMBER GEESMAN: That's just another way of saying you don't know after 2012.

MR. PRETTO: I think after 2012 it's very difficult because I think the forecast that we saw here today, a lot of that is driven by expectations of LNG arriving.

I looked at, for example, it's not available to actually use here, but our CERA forecast which we subscribe to indirectly through NCPA, and they've got gas prices behaving a they did in this manner. Yet the actual gas prices remain -- keep coming in higher than some of those forecasts indicate.

The other kind of wild card, I think, in this that I don't think anybody's had a real opportunity to evaluate is the impact of greenhouse gas reduction legislation as it evolves. Because that can have an impact on how coal plants develop. And if they don't develop at a pace that most people are forecasting -- they get more expensive, I think that's going to impact the prices of natural gas and flow back and have an impact on us ultimately.

But I don't think anybody has the ability to quantify that right now.

ASSOCIATE MEMBER GEESMAN: And does anybody else, other than this Commission, ask you for a ten-year projection?

MR. PRETTO: Not that I'm aware of.

ASSOCIATE MEMBER GEESMAN: When you sell bonds do you make a ten-year projection of your rates?

MR. PRETTO: We do not.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: Nick.

MR. ZETTEL: Yeah, the City of Redding is fairly similar to Silicon Valley Power. We have a set of fixed-price laddered contracts that begin in certain years and end in certain years for our fuel requirements.

The City of Redding, we don't forecast natural gas, but we do review forward curve forecasts from producers or sellers, suppliers. We review the forecast from the Energy Commission, EIA. We also subscribe to CERA indirectly through NCPA.

So in our review, in our pricing, we take a look at that. But at the end of the day what really matters is what you can buy it for, not what -- you know, if we could buy gas for what the EIA forecasts for, life would be great. But unfortunately, the EIA doesn't sell gas.

But like Mike said, there's some bogies. Demand for greenhouse gas regulations push the gas. But there's also other issues like what will pricing do with offset demand for renewable energy. If we continue on a march to 30-plus percent RPS goal, will that lower the demand for gas. But these are things that are fairly immature and we don't think you can have a firm grasp on pricing.

ASSOCIATE MEMBER GEESMAN: Just so that our transcript is clear, both you guys mentioned CERA. That's C-E-R-A, and it stands for Cambridge Energy Research Associates?

MR. ZETTEL: Yes.

MR. PRETTO: Yes, it does.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: Rick, I saw you shaking your head. Are you answering this for PG&E?

MR. ASLIN: No, --

MR. ALVAREZ: I'll answer it.

MR. MELLOR: Antonio, sorry.

MR. ALVAREZ: We do not have a crystal ball as anybody else here would have it, and so what we do is we have developed areas that tend to bracket the original uncertainty that we have with respect to natural gas prices, as well as electricity prices.

In the case of natural gas prices, as others have said, we rely on forward market prices. And relative to that we developed scenarios that had a plus or minus, I would say, 30, 25 percent; more on the high end than the low end. And those were the scenarios that we prepared and were used to project rates.

We do not forecast prices, but what we have done for the long-term planning, this is the one that we file with the Public Utilities Commission in November, I believe, we use the forward prices. And then at the end, towards the 2011, 2012 we switch to an average of market price forecast which are the basis for the 2006 -- at that point. So it's a combination of price forecast.

So, you will see that the switch from a forward price to a model average, you know, produces that trend that, you know, was mentioned before.

ASSOCIATE MEMBER GEESMAN: I wasn't clear what happens after you get off the forward curve. You average third-party forecasts?

MR. ALVAREZ: We switch to an average of modeled forecasted prices that are the basis for the 2006 market price referent that is used to benchmark renewable resources.

ASSOCIATE MEMBER GEESMAN: Okay, so it's the same as the market price referent price for those out years?

MR. ALVAREZ: Yes.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. ALVAREZ: There might be a one- or two-year transition where, you know, things don't quite line up perfectly.

ASSOCIATE MEMBER GEESMAN: Right. And does anybody other than this Commission ask you for a ten-year projection?

MR. ALVAREZ: Projections are needed to do long-term plan, so we have, as a course of developing our long-term plan, provided those projections to the CPUC in filing.

ASSOCIATE MEMBER GEESMAN: And do you include that type of long-term projection in your 10K or any of your securities filings?

MR. ALVAREZ: I don't know the answer to that question.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: After hearing discussion among the panel members, are any of the members wanting to add anything else regarding natural gas before we leave that topic.

MR. PRETTO: I had one thing. One thing because Ken did ask, the relative importance of gas costs, our electricity price projections, really our cost projection, because ultimately cost gets translated to price.

Gas costs are about a quarter to a third -- have become in the last couple of years, gone from essentially zero to between, I'd say, a quarter and a third of our total cost of doing business. So it has had a significant impact.

And the other dimension of gas costs that ultimately in trying to secure additional renewable energy, we're at 30 percent renewable right now. And actually trying to maintain and increase that. In some respects, it's good because the renewable market tends to favor fixed prices.

And what I'm beginning to like bout fixed prices instead of index prices is that gas, I think, has a tremendous amount of volatility in it. And forecasts don't do a very good job of capturing that future volatility.

But ultimately we're looking at more renewables because of basically fear of that future gas price volatility.

PRESIDING MEMBER PFANNENSTIEL: So, Mike, as you have more renewables in your out-year forecasts, does that show up in terms of the numbers that you file? How do we see that?

MR. PRETTO: The way we structure the forecast currently, no. It really doesn't show up. To the extent we have open positions in the future where you're going to fill in with what I would call unspecified resources at this time, we basically made a kind of a market price referent assumption in terms of how, you know, future contract prices would look like.

So, nothing specific in terms of fleshing out that assumption, or that belief, if you will.

COMMISSIONER BYRON: If I may ask the panel, this issue came up in a different way, so I'll ask you more directly. Do you agree with the staff report in terms of reflecting the price projections that you provided?

MR. SNOW: I believe they used the ones that we provided.

MR. HANSEN: Yes.

MR. ALVAREZ: Yes.

MR. SPEAKER: Yes. Factor only

represents the number that we provided.

COMMISSIONER BYRON: Thank you.

MR. MELLOR: I'd just make a couple of comments before we move on to the next. One is our observation has been that renewable contracts early on included indexing the natural gas prices, and we're seeing less and less of that. So hopefully that will not influence the price for renewables in the future.

And secondly, that the model, as it was built, allows you to go in and use any gas price forecast you want to use. And test the sensitivity of the electric price forecast to natural gas prices.

MR. ALVAREZ: One other thing that I wanted to --

PRESIDING MEMBER PFANNENSTIEL: And kind of make sure that you're using -- that mike doesn't project. I think you need to make sure that green light is illuminated on it.

MR. ALVAREZ: Yeah, you know, hearing the question, I thought I don't know if it is appropriate for this IEPR, but I think it is important to recognize that there is uncertainty with respect to gas prices and electricity price projections.

And I think if not in this IEPR, but perhaps in the future one it will be good to have more range, I think Dr. Pechman made the same observation that a single-point forecast is perhaps not as useful, because we know it's going to be wrong. So that may be appropriate in a future time.

ASSOCIATE MEMBER GEESMAN: I think that's good advice.

MR. MELLOR: Okay, let's switch to renewable resources and other regulatory requirements that are similar to renewable resource requirements.

What assumptions have panel members made with respect to the percentage mix? And it's been mentioned that we now have an objective. Many people think that objective's going to change in the future. So, in your forecasts what have you assumed.

And how does the ability to schedule those resources affect the pricing that you're putting into your forecasts? What premiums, if any, are you placing on the cost of those resources, including the cost of capacity backup, greenhouse gas regulations, and other expected regulatory changes where required? And what effect will that have on your retail price forecasts?

Let's start again with you, Doug.

MR. SNOW: Sure. Our forecast assumes that we will reach the 20 percent RPS standard by the 2011/2012 timeframe. Currently Edison has about 16 percent renewable in their portfolio, which is biomass, geothermal, small hydro, solar and wind.

So that's already built into our forecast. We did not build in any premiums. Those were all priced at the market. So to the extent, you know, that there are premiums that materialize that's not built into our forecast.

MR. MELLOR: Let me just follow up with that. How about premium in terms of the schedulability, or is that factored in somehow?

MR. SNOW: That's factored in.

MR. MELLOR: Okay.

MR. SNOW: Schedulability.

MR. MELLOR: Bob.

MR. HANSEN: For SDG&E we also assumed having the 20 percent standard by 2010. And we assume increases of about 1 percent per year thereafter. And the costs that we add were at no higher than the market price referent. So market prices would be the ceiling.

Increases to renewable power at $10 per megawatt hour equates to about .1 cents per kilowatt hour in the analysis we did, as far as the sensitivity to the renewable power.

And we have not done any -- not included any costs of future greenhouse gas reductions. We believe it's too early to know what impact that might be.

MR. MELLOR: Mike.

MR. PRETTO: I think I described in part how we conducted our forecast. At the time it was constructed we were seeing, in terms of the renewable acquisition we were doing, we were seeing renewables be about where our perception of market energy prices were.

I think if we were to do the forecast again today with later information I think we might show for the renewables -- for new renewables a bit of a premium to what we would perceive the other basic market price of gas to be, which would be based upon, you know, take your gas price forecast, multiply it by heat rate, and that'll get you capacity-free energy price.

That kind of describes our assumptions about the market energy. And I think renewables we should probably, in the future, have some kind of premium to market energy for, you know, for renewables. For new renewables.

MR. MELLOR: Nick.

MR. ZETTEL: When Redding initially dove into renewable energy resources we were seeing prices that were somewhat on par with the market under conventional long-term agreement, or generator.

Recently, prices for renewables have kind of moved off the curve, away from market prices, conventional market prices. And I think some of the fundamentals behind this is you have the State of Washington, State of Oregon, Nevada and majority of other states in the WECC have enacted an RPS requirement which places pressure on existing resources, and also pressure on utilities to find resources.

And then on the supply side there's been other countries in the world that are, you know, demanding renewable energy resources such as wind turbines and other things at amazing rates. And renewables are no longer priced on the market or the market price referent. Renewables are priced on demand.

Redding is assuming a 20 percent by 2010, and actually we're sitting somewhere around 32 percent under the state's definition of eligible renewables right now. Greenhouse gas costs, too early to tell. Depending on the structure. If it's cap-and-trade or a fee or a tax or what-have-you.

We don't place premiums on resources. The premiums are in them already. Scheduling, it's in it. It is what it is, by the time you get it home, the costs have been put in.

MR. MELLOR: Antonio.

MR. ALVAREZ: We have -- we're projecting -- well, let me, a little background. We have, as part of a long-term plan, we've prepared three candidate plans. A basic procurement plan; an increased reliability plan; and then an increased reliability and preferred resource plan. That last one is our recommended plan.

The recommended plan, as well as the other plans, the meet the 20 percent requirement for RPS. And for 2016, the first two, the basic procurement and the -- reliability plan, they have the same range of RPS percentages between 21 and 27 percent, depending on the scenario.

The recommended plan has about 1 to 3 percent additional renewable resources. And so we are, you know, depending on availability, someplace between 23 and 30 percent by 2016.

With respect to the premium, we did compare the cost of the plans relative to -- well, basically the basic plan relative to the increased reliability and increased preferred plan, and we found about .1 cent per kilowatt hour -- this is in terms of sales -- increase associated with the additional renewable resources.

And those come in two flavors. And I really can't tell you exactly what the breakdown between those two components are. But one is the premium and the other one is the integration costs. And so, anyway, that's about what it is, about .1 cent per kilowatt hour.

We, in terms of integration costs, what we have assumed as a proxy for now is we accounted for the value of shallow capacity and assume about a $5 per megawatt hour integration cost for wind.

ASSOCIATE MEMBER GEESMAN: Now, somewhere north of 90 percent of the RPS contracts that the investor-owned utilities have signed to date, have come in below the market price referent. So I take it PG&E envisions that changing going forward?

MR. ALVAREZ: Yes. Yes.

ASSOCIATE MEMBER GEESMAN: And what's the rationale for the change?

MR. ALVAREZ: I think some of the comments that Nick made just, you know, there's an increased demand for renewable resources, and a limited amount of supply.

ASSOCIATE MEMBER GEESMAN: Of course, if you go outside California the supply is close to infinite in terms of the projections made by the wind industry and in Nevada the geothermal industry. When you say there's a limited supply are you focused principally on your service territory?

MR. ALVAREZ: No, we're always looking at other areas besides the service area. But the prices that we have seen are above, you know, our market price referent estimate.

PRESIDING MEMBER PFANNENSTIEL: Okay,

you calculated this .1 cent kilowatt hour premium based on preparing a couple difference resource plan scenarios, including renewables? I want to make sure I understand how that was done.

MR. ALVAREZ: Yes, yes, what we did is we prepared three plans that emphasized different choices. The basic procurement plan was, you know, met the basic reliability and preferred resource requirements.

The increased reliability plan had a higher reliability than the basic procurement plan. Then the third plan, trying to achieve the same level of reliability with an increased amount of renewables.

So, when I say .1 difference I'm comparing the last two plans. And that's the levelized -- kilowatt hour levelized --

PRESIDING MEMBER PFANNENSTIEL: And it wasn't just the capital cost of the renewables, it was the integration --

MR. ALVAREZ: Right.

PRESIDING MEMBER PFANNENSTIEL: -- the system costs.

MR. ALVAREZ: Yes.

ASSOCIATE MEMBER GEESMAN: I want to

come back to what you'd said in response to my question. You said the prices you were seeing had led you to assume higher than MPR cost for renewables.

Is that the prices you've been seeing in response to your solicitations, or is that the prices you've been seeing in bilateral negotiations? Or is that the prices you're simply expecting to see in the future?

MR. ALVAREZ: Both, in terms of solicitations and in terms of bilateral negotiations that we have.

ASSOCIATE MEMBER GEESMAN: And can you share any of that with this Commission?

MR. ALVAREZ: I have a very limited knowledge. You know, being more in the planning organization, not close enough to the commercial.

ASSOCIATE MEMBER GEESMAN: You might carry back the request to whoever it is on your staff that would be in a better position to know what can be shared and what cannot be.

MR. ALVAREZ: Okay.

ASSOCIATE MEMBER GEESMAN: Because in an empirical database that suggests in excess of 90 percent of the energy and capacity secured under

RPS contracts to date, at below the market price referent, your suggestion of a -- change, I think, could really be bolstered by some documentation.

MR. MELLOR: Further questions from the Commission? Any additional comments by the panel?

MR. PRETTO: Just one comment in response to Commissioner Geesman. You suggested that there's renewable resources are very large outside of California. I think probably there is suggestions from the proposals that have been brought to us that that may be true, there is power out there.

One of the concerns we're starting to have, though, is in dealing with people who want to negotiate with us, is they need to show us the transmission path that will get it to the California border. We can manage it once it gets here, but getting it here can be a challenge.

ASSOCIATE MEMBER GEESMAN: Well, I think that you're a member of TANC, are you not?

MR. PRETTO: Yes.

ASSOCIATE MEMBER GEESMAN: And you and PG&E are jointly exploring transmission opportunities in the northwest, as I understand it.

MR. PRETTO: But those are in the future, they're not today.

ASSOCIATE MEMBER GEESMAN: Right, right. I also presume that transmission outside California may be easier to site than transmission inside has proven to be, simply because you won't have to deal with the Public Utilities Commission. But that may be a false assumption.

MR. MELLOR: I have one followup question of the investor-owned utilities with respect to the market price referent, as to whether you're assuming that whether it's 10 percent of 20 percent or whatever percentage of the resources that come in that are renewable are above the market price referent, whether you and your forecasts have assumed that there's enough money in the public goods charge funds to support that additional amount over the market price referent. Or are you assuming a higher cost than the market price referent for some of your renewables?

MR. SNOW: Edison has used the market price referent for the renewables forecast.

MR. HANSEN: Yeah, same with SDG&E. That provides a cap for our renewable pricing.

MR. MELLOR: Okay, so you're assuming there's enough money in the public goods charge to support that additional amount?

MR. HANSEN: Yeah, I guess I'm not sure how it relates to the public goods charge revenue as far as the renewable component of the --

MR. MELLOR: Okay.

MR. ALVAREZ: I don't know the answer to your question. I can check and find out. But my assumption is that whether it is part of public goods charge or not, it is part of the total cost that the customer pays. So, I'm not sure -- I know too little to answer your question. But I think it should be reflected in the cost, in the retail rate, anyway, except for the allocation of the public goods charge --

ASSOCIATE MEMBER GEESMAN: I hate to keep picking on PG&E, but I believe in your procurement filing with the Public Utilities Commission, you had placed a 10 percent limit on the amount of wind you will be purchasing, at least in the long-term procurement plan that you'd filed with the Public Utilities Commission.

Does that 10 percent limitation carry through to the assumptions you've used in these price projections?

MR. ALVAREZ: No, we did say that we had placed a 10 percent limit on incremental wind generation. But that limit was not a binding constraint as far as the amount of wind that we added through 2016. Ten thousand on an incremental basis on a load of, you know, close 100,000. It's a large amount of wind. So it wasn't a constraint for us.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: Okay, let's jump topics. One of the discussion items this morning was how much capital is built into your program; and advanced metering is one of those that plays a fairly major role in some of the utilities programs.

So this question is the evaluation of advanced metering and advanced distribution impacting your estimates of the cost of distribution and customer care? And to what extent? How important is that factor?

MR. SNOW: Well, it certainly impacts the revenue requirement forecasts that we have. We have assumed our deployment will be full until 2012. I think we'll start in 2008 and fully have deployment in 2012.

I think we're estimating about a billion dollars in capital. And so that is built into our forecasts.

ASSOCIATE MEMBER GEESMAN: What about other investment in the distribution system? How does your forecast incorporate that?

MR. SNOW: In the early years, kind of what you were talking about at the beginning of the workshop, we actually have a hefty capital investment built into our forecast. I think about $17 billion on the T&D side. And so that's built in through 2011.

And then after that we really don't know, this was also talked about, what's going to happen going forward. And so that is kept flat.

What's not kept flat is the procurement side, which is kind of based on the gas price forecasts that we saw. So we do have a forecast all the way through 2017 for procurement. We have built in, you know, a pretty hefty capital investment through 2011. And then that has kind of remained flat after that.

ASSOCIATE MEMBER GEESMAN: When you say flat, does that mean a continuation at some previous trend level?

MR. SNOW: Right. It would be built right up at the 2011 amount. So, you know, we're not reducing that; so we're just continuing that. Not increasing investment much more than that. It's keeping the average price the same.

ASSOCIATE MEMBER GEESMAN: I'm still confused. The increment of capital investment going to T&D after 2011 would be the same as it was in the year 2011?

MR. SNOW: It increases a little bit, just because as, you know, the denominator in your price forecast of sales. So as that's increasing, we're also then increasing the numerator. So we're keeping the price flat. So it's increased. But we're not including, you know, specific projects beyond 2011.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. SNOW: Does that make sense?

ASSOCIATE MEMBER GEESMAN: Yes, it does.

PRESIDING MEMBER PFANNENSTIEL: And so it's flat per kilowatt hour sales, but not for customer growth, for example?

MR. SNOW: Right, right.

MR. HANSEN: For SDG&E it sounds like,

at least some aspects are quite similar to Edison. We're including advanced metering costs based on the approved settlement by the CPUC. So those costs are rolled into both the benefits and the costs on an annualized basis consistent with that settlement for the duration of this forecast.

The other costs for distribution, for example, we're assuming the general rate case is adopted as proposed in 2008. And after that we're assuming performance-based increases based on proposals applicable to distribution through 2012.

And then after 2012 we apply a standard escalation to the distribution amount based on that assumption for --

ASSOCIATE MEMBER GEESMAN: And your standard escalation is what?

MR. HANSEN: I believe that would be like a CPI type increase assumption. So, flat in real terms, or at least a component of the distribution.

MR. MELLOR: Before we go on, Mike, I want to follow something up here. I'm trying to get a sense of how important this is. And the reason for that is we're seeing a substantial increase in the first two or three years in these forecasts and then a tapering off.

I'm trying to determine whether the large capital expenditure for advanced metering and smart distribution, whatever you call it, is going to result in lower operating costs in the future. So I'm trying to see to what extent all that plays out.

And coming back to you, Doug, what does a billion dollars in meters mean in terms of annual revenue requirement? And what percentage of total revenues is that? And do you think that the investment in advanced metering is going to have payoffs in terms of lower operating costs in the future? And has that been built into your forecast?

MR. SNOW: Yes, both sides have been built in. You know, as we're ramping up I think the revenue requirements in the neighborhood of $120 million a year based on that billion-dollar investment.

We have, you know, also built in savings and there are also, you know, kind of like more weighted at the end of the forecast. As, you know, we're deploying the meters and everything.

And then as those meters start

depreciating I think that's when we're going to get most of your, you know, a lot of your benefit. Plus also on the procurement side, to the extent that, you know, there is demand response as an outcropping of the AMI.

So we also have an assumption; it's pretty crude right now. As we know more going forward we'll certainly refine our forecast. But we attempted to forecast both cost and benefits.

MR. MELLOR: Bob, can I ask you to kind of respond to that same --

MR. HANSEN: Sure. For SDG&E it's a similar situation, $470 million is the capital cost which equated to about $50 million in revenue requirements, declining over time, with benefits increasing in the later years. Full deployment by 2012.

So there is a cross-over point, but I'm not sure if it occurred within the forecast period. Eventually they do cross over.

MR. MELLOR: Mike.

MR. PRETTO: Santa Clara's capital forecast is actually driven by substation transformer and switch-gear replacement over about a five- or six-year program we have begun. And that's reflected in this forecast.

Many of our substations were built in the '50s and the '60s. We're getting to be 50 years later, which is kind of the expected life. So we're starting to reflect that kind of capital cost in our forecast.

As far as the advanced metering, we're beginning to do a little bit of that. We do not have an assumption in here as to any large scale installation of advanced metering in Santa Clara. We do have advanced metering on all of our largest customers which in terms of our -- once you cover those you've covered a substantial portion of our total sales.

MR. MELLOR: Nick?

MR. ZETTEL: Yeah, the City of Redding, in the assumption in the forecast, didn't put dollars in for advanced metering. It's not because we don't think it's a good thing or think it works, it's just because we're not sure how it would benefit the customers of the City of Redding right now.

So before we, you know, spend a billion dollars on advanced metering, -- that's a joke --

ASSOCIATE MEMBER GEESMAN: That's what

you figure it would cost -- in Redding?

(Laughter.)

MR. ZETTEL: What we're really facing is existing distribution expenses are skyrocketing. Transformers have doubled; poles have doubled; lines have doubled. The cost of metals and materials, because of world pressures and other issues, has really put a lot more pressure and put distribution on the map as far as the budgeting process goes. And we're still dealing with that before we jump in headfirst into advanced metering.

ASSOCIATE MEMBER GEESMAN: And what do you show in terms of your distribution investment in this forecast?

MR. ZETTEL: Oh, dollarwise?

ASSOCIATE MEMBER GEESMAN: Well, how did you calculate it?

MR. ZETTEL: Well, we actually consulted our distribution division. And they have a capital plan as far as substations and transformer change-outs. And then just routine expenditures based on the cost of materials and a forecast of cost of materials based off an index, I do believe is what they used.

ASSOCIATE MEMBER GEESMAN: And is that front loaded in the first part of the ten-year period, or is it --

MR. ZETTEL: It's fairly steady. Our replacement program is fairly steady for the years.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: Antonio or Rick.

MR. ASLIN: I'll take this one. So, yes, PG&E also included the cost of installation, operation and maintenance of advanced metering infrastructure for all five million customers during the forecast horizon. And that's a total capital spending over that period of, I think it's $1.25 billion.

And the question as to what effect it would have on the rate trajectory of AMI, itself, depends on where you start. If you start it in 2007 and you look at your rate trajectory from that point forward, it wouldn't have any impact at all because we're already spending that money in 2007. It's in 2007 rates. But if you looked at 2005 rates, then the increase would be -- it's about 50 million to 75 million a year in revenue requirement.

So it just depends on where you look, as to how it impacts the rate trajectory. But I would point out also that our total revenue requirements are around 10 billion. So, advanced metering infrastructure is not having a big impact on the rate trajectory.

MR. MELLOR: And that's net of capital expenditures? I'm trying to get a sense of how you're amortizing your capital costs with lower O&M costs. And whether or not it's looking like a cost effective program.

MR. ASLIN: Yes, it is a cost effective program. And yes, we do have the expenses going down to offset the increase in the capital spending.

MR. MELLOR: Okay.

ASSOCIATE MEMBER GEESMAN: How do you address the rest of your distribution capital investment?

MR. ASLIN: I think for our distribution capital investment -- well, our total capital investment over the first five years is from our long-term investment plan. So that's right around $2 billion per year.

I think that's pretty much evenly split

between distribution and transmission and distribution.

And after 2011 then we go back to trend spending. So, for distribution, itself, that's close to $1 billion a year in capital. But we should also keep in mind that our depreciation of existing capital is around $1 billion. So we're not hitting a big impact on our rate trajectory from distribution capital spending, either.

ASSOCIATE MEMBER GEESMAN: And when you revert to trend, how do you determine the trend or calculate the trend?

MR. ASLIN: Well, I didn't determine that, myself. I got that from our financial planning and analysis department. But they essentially looked back over the last, you know, five or ten years, what our capital spending was on distribution.

ASSOCIATE MEMBER GEESMAN: Of course, that period of time covers the bankruptcy and -- I mean a lot of arguable anomalies in that period of time.

MR. ASLIN: I'm assuming that they applied some judgment there as to how the bankruptcy affected the distribution capital spending.

MR. MELLOR: Any other panel comments?

Okay, let's jump back into generation. And part of this is driven by changes in people's expectations of portfolios as to whether you're going to self-generate, contract out, that kind of thing.

We're trying to figure out, in terms of the information you provided to the Commission, how you're addressing the cost of building new capacity for generation, retiring old generators that are ready to be retired, and any discussion of transmission added to, that would also be helpful.

MR. SNOW: Edison hasn't forecasted that we would be building any new generation. Obviously the Mojave plant is forecast to be retired, or to be taken out of service.

However, you know, the procurement costs that we are entering into through the RFO process would probably, those prices are based on what it would cost to build new generation. So that has been factored into our forecast for pricing new capacity.

MR. MELLOR: Because of your process of

acquiring it here --

MR. SNOW: Right.

MR. MELLOR: -- you're using your own cost as a baseline.

MR. SNOW: Well, not our cost, just what the cost to build new generation would be. But it would not be Edison-owned new generation.

ASSOCIATE MEMBER GEESMAN: Often your company makes the argument that there's a dead equivalence that needs to be accounted for in these long-term procurement contracts.

Did you make an explicit adjustment for that dead equivalent?

MR. SNOW: I cannot answer that. I do not know.

MR. MELLOR: And how about transmission?

MR. SNOW: I mentioned transmission before in that big investment that we talked about. That also included, I think, about a little for $4 billion in transmission investment.

MR. MELLOR: Okay.

ASSOCIATE MEMBER GEESMAN: And is that determined by identified projects, or a consistent rate of investment in transmission?

MR. SNOW: There again would be

identified projects through 2011; and then it's the same, you know, we kept that flat. So I believe the forecast does include, you know, the Devers-Palo Verde line which is having some problems now. But that's also built in.

ASSOCIATE MEMBER GEESMAN: Yeah. Thank you.

MR. MELLOR: Bob.

MR. HANSEN: For SDG&E the costs provided do include resources needed to meet the CPUC's adopted resource requirements. As far as the increases in the cost of capacity and how that would impact it, it's hard to say. That didn't have a number on exactly what that increase or changes that would cause.

For transmission we do include any projected costs of filed and proposed transmission line additions, such as the Sunrise Power Line. And also, it's a statewide revenue requirement, so we're assuming 10 percent of our estimates of statewide investment in transmission based on at least known transmission line additions in the later years.

ASSOCIATE MEMBER GEESMAN: But you didn't create any generic transmission investments? They're all project-specific?

MR. HANSEN: That's right.

MR. MELLOR: Mike.

MR. PRETTO: Okay. Santa Clara's capacity availability is currently, and actually pretty much for the foreseeable -- for the next ten years, is in excess of our demand. We have a lot of hydro-based capacity that you could count toward capacity adequacy requirements.

Our needs ultimately are not capacity, per se, but for energy. And in that regard we are looking, along with NCPA, at least one, participating in at least one project. We're considering a couple of others.

To the extent those are successful that will provide us with the capacity that we need. If it's not available the time of the year that we need it, tends to be a time when capacity is available. It's not during the summer.

ASSOCIATE MEMBER GEESMAN: Do you still have Western contracts that make up a fair amount of your resources?

MR. PRETTO: We have Western contracts that make up a fair amount of capacity. They used to be a lot of our energy, but they are no longer.

ASSOCIATE MEMBER GEESMAN: Okay.

MR. MELLOR: Nick.

MR. ZETTEL: Yeah, when Redding reviews the cost of capacity, in resource planning when you do a load and resource balance and you go out and you look at, okay, what year will I need additional capacity to meet my planning reserve goal, which Redding currently uses 15 percent.

In California the cost of capacity these days is either a combined cycle gas turbine or transmission line to a place that'll get you resources that fit under the guidelines of 1368.

Something to keep in mind is there are opportunities in California to replace older units that are less efficient. And when you do such a thing under the gas prices we live with today, the efficiencies from the new units can sometimes pay for a portion or all of the new debt that you acquire.

So, in our long-term forecast we assumed that the cost of new capacity was in our purchase power line item.

ASSOCIATE MEMBER GEESMAN: Now, when you look at replacement of existing units, are you speaking from Redding's perspective of its own resources, or was that a larger generalization?

MR. ZETTEL: I think a larger generalization.

ASSOCIATE MEMBER GEESMAN: Because that was clearly a big theme we tried to hit upon in the 2005 report, with spotty results, I think, between the different utilities.

MR. MELLOR: Back to you, Antonio.

MR. ALVAREZ: Yes. Our rate projections included the cost of the resources that we just procured through the last -- we executed in 2006. And it also includes the additional amount of new residual resources that we need in order to maintain the minimum current resource adequacy requirement. This is in the first two procurement plans that I mentioned, basic procurement plan -- excuse me, just the basic procurement plan in the high reliability plan.

We also have -- also in the high reliability and high -- resource plan we have additional capacity, peaking capacity that it needed in order to meet that higher planning reserve margin. And for that we're using basically the net cost of a combustion turbine to capture the increased generation cost.

ASSOCIATE MEMBER GEESMAN: And do you envision owning generation resources as a utility?

MR. ALVAREZ: Yes, but we haven't quite, you know, depends on the results of the competitive solicitation, whether the resources they're owned or purchased.

ASSOCIATE MEMBER GEESMAN: So in this projection did you make any assumption as to what the mix would be between owned and procured resources?

MR. ALVAREZ: No. We just, for the most part, in order to make the numbers easy to calculate we assumed purchases, but, you know, that's to be decided based on the results of the RFOs.

ASSOCIATE MEMBER GEESMAN: Did you make any adjustment in your cost of capital to pick up this so-called dead equivalence issue?

MR. ALVAREZ: I don't know the answer to that question.

ASSOCIATE MEMBER GEESMAN: What about transmission?

MR. ALVAREZ: My understanding is that we include the cost of whatever projects are included in our transmission plan, the one that we submit to the ISO.

ASSOCIATE MEMBER GEESMAN: This is a longer period of time than that transmission plan covers, isn't it?

MR. ALVAREZ: Well, I don't know, I suspect it is. I don't know the answer to that. Sorry.

ASSOCIATE MEMBER GEESMAN: But if I understood your answer correctly, you focused on discrete projects, you didn't have a generic transmission category for capital?

MR. ALVAREZ: Yeah, those that are identified in the plan, yes.

ASSOCIATE MEMBER GEESMAN: Thank you.

MR. MELLOR: Other Commissioner questions?

COMMISSIONER BYRON: If I may, you know, obviously a lot of these questions -- all these questions are directed towards trying to understand the revenue requirements and making sure that we get a sense that they're all in.

I guess I have a more fundamental question, and I'll admit a certain naivete with regard to rate structure development. Seems more straightforward with publicly owned utilities.

But I guess fundamentally my question would be to everyone on the panel, what obligation do you have to get these costs right, these revenue projections correct. Obviously natural gas increases with the pass-through costs, if they go up.

But what about other unexpected costs that might come in that you can't foresee? What obligation do you have to be as right as you can be on these revenue projections -- these revenue requirements?

MR. SNOW: I guess we made a very good faith effort to get what we believe, with the information that we have today, what these price forecasts would be. Obviously, the Commission here is undertaking to try to use these price forecasts in coming up with a load forecast for the state that will be used, you know, by a lot of different folks.

So in that regard we certainly tried to do a lot of the forecast, what our rates, our revenue requirements would be for this period to 2017.

Does that answer your question?

COMMISSIONER BYRON: Would anyone else

care to give it a try?

MR. HANSEN: Similar for SDG&E. We wanted to do a bottoms-up type estimate and be consistent with any other projects that we know existed, or were proposed. So, to the extent all knowns were taken into account in the forecast that we had. And then anything that remained, then we have to make assumptions for that. And that's where it became more of a CPI indexing for any outlier or issues or categories that we didn't have specific plans for.

COMMISSIONER BYRON: Before I ask my next question, Mr. Alvarez, did you want to respond, or Mr. Aslin?

MR. ASLIN: I think I can. I'd say a couple things. One is we do feel a responsibility to try to get it right because we understand that this is a document that's going to be published. And we have referred back to, for example, the 2005 IEPR also published a table of all the utilities' rate trajectories. So we do reference back to that.

A couple of things. One is that we are currently still in the midst of litigating our long-term -- plan, and so we leveraged that to the extent possible. And the other thing that we brought in was our five-year business plan, which we're also very committed to.

So, we have a pretty high level of commitment. Having said that, certain things that we understood from the beginning that we were not going to be able to forecast, such as gas prices and the level of market acceptance of renewables over time and things like that. that's why we submitted four scenarios instead of just the one point forecasting.

I'd like to just reiterate this whole idea that was brought up earlier that it might be a good idea going forward to try to get away from the point forecasting as much as possible, especially for maybe generation costs. And, you know, go to some sort of range of forecasts. I think that would be more -- I don't know if it would be more useful because it's actually harder to use a range, but it would certainly be more informative.

COMMISSIONER BYRON: Agreed. So what about the uncertainties, other than natural gas price. Weather clearly is a major uncertainty that we've seen come into play. Is there any effort to put some sort of probablistic risk assessment associated with these kinds of issues. We know that we'll have weather events. We know that we'll have major capital costs associated with a large earthquake, for instance. Are any of these kinds of things put into the revenue requirements?

MR. SNOW: I would believe for Edison that like weather would just be normalized. I mean, you know, if we didn't like forecast in a certain year there was going to be, you know, a big rainstorm or an earthquake. But, you know, over time, you know, we have an average weather year, an average storm year built in.

MR. HANSEN: Yeah, that's similar for us. Demand and load forecast would take into account the conditions for weather, and it would be more of a normalized situation in the long run.

MR. PRETTO: Our forecast is based on average hydro conditions and also implicitly assumes that wet years and dry years will tend to offset each other.

The other impact that could occur that would ultimately affect rates, but for example, if you had a year with a big gas price spike. We have, what we do in Santa Clara, is we have basically set aside some cash reserves to cope with that.

So if a gas price spike occurs we don't have to have an immediate effect on rates. But at some point in the future, if we want to restore that particular level of cash reserves, we will have to manage our rates in order to accomplish that.

MR. ZETTEL: Yeah, at Redding we employ a similar manner. Let's take, for example, a catastrophic event like an earthquake. We don't forecast or have revenue requirements for an item like that. But weather is normalized, and in Redding it's normalized a little hotter in our forecast.

We have recently gone from 110-degree average to 112 degree after seeing some weather patterns.

We also have cash reserves for ultra-dry hydro years. But in the long term we assume average. And as far as gas price spikes, before we get into the actual year Redding is hedged nearly 100 percent on fuel requirements. So we don't leave ourselves susceptible to the May-through-August hurricane pricing fears, and then it doesn't materialize, and it flattens out in October through November, and then it gets cold and the price goes back up. We can't put our customers through that type of grief, so we flatten that out through -- contracts.

MR. ALVAREZ: A couple of thoughts come to mind. One is the way we try to deal with uncertainties is we try to classify them into three different buckets. So far, you know, if I think about the ones that we've discussed, weather and price volatility we treat them more as cyclical, kind of reverting type of uncertainties. And for those we do probablistic simulations just to look at the probably distribution of the resulting price to customers.

In addition to that, we look at structural, long-term uncertainties such as movements in, you know, movements in price, load growth. And for those we develop the scenarios. And those are the scenarios that I mentioned before.

And just thinking about whether, since you mentioned, we haven't included yet but it's possible that in the future we might start looking at the effects of climate change and try to reflect that into either our probablistic or the kind of structure load growth assumptions.

COMMISSIONER BYRON: A lot of uncertainty around understanding that. Thank you, all, very much.

PRESIDING MEMBER PFANNENSTIEL: Some years ago the Public Utilities Commission considered, for the investor-owned utilities, ratemaking under a performance-based ratemaking formula where you would do a projection of your costs, all end costs, fuel, plus capital, escalated probably by something like a CPI, reduced by something like a productivity index, and then the utilities would agree to abide by those prices, trying to stay within them.

When I look at the kind of prices we're looking at here, which is essentially declining real prices, in other words it looks like you guys' productivity is, you know, great offsetting any inflationary costs.

And yet there clearly is no intention of abiding by these kinds of costs. As I remember, the problem with what the PUC was considering at that time is that the utilities would, in essence, commit to some period of time like a five-year block of years or something at these price levels. Whatever had been agreed upon.

I don't see these with that same kind of commitment. This is an estimate -- at that time, in fact, the other way -- the utilities went the other way trying to load in all of the possible capital investments that you could anticipate, because you didn't want to get caught short.

This looks like, in fact, you have the known capital upfront, but beyond that you're not really trying to be quite as realistic as I think you might have been if you were being held to these costs.

Does anybody remember the performance based ratemaking discussion and is that at all -- that kind of thinking relevant to trying to get some good estimates going forward today?

Nobody was around then?

MR. SNOW: Certainly for Edison it wasn't an all-in. Our fuel procurement was never part of that mechanism. It was just on the base side.

PRESIDING MEMBER PFANNENSTIEL: It was - - as I remember, the idea was the overall cost was estimated and then they separated out the fuel part.

MR. SNOW: Yeah, the indexed revenue requirement was just basically our distribution, our --

PRESIDING MEMBER PFANNENSTIEL: Right, but then there was a --

MR. SNOW: -- nonFERC --

PRESIDING MEMBER PFANNENSTIEL: -- commitment to the fuel. Okay.

Go ahead.

MR. ASLIN: I do remember it somewhat. One thing that was brought to mind when you mentioned that, though, was if you look at the trajectory here, this was probably one of the biggest arguments against performance-based ratemaking, is how well you do as a company in terms of your earnings has all to do with where you are in the investment cycle.

So, we're talking about some fairly lumpy investments that we're making in transmission and generation. And so it all depends on the time period and where you are in the investment cycle when you start that time period.

So that was one of the things I recall about performance-based ratemaking that made it difficult for everybody to agree on.

MR. MELLOR: Okay, we're going to jump to the last question. So far we've been talking about cost drivers. Now I want to talk a little bit about how your projections have taken into account demand management, conservation, all those things that would tend to change the load patterns that you're serving. And how are the costs of accomplishing those built into your forecasts.

MR. SNOW: Well, for Edison when we come up with our load forecast, obviously a lot of it's driven from historical, normalized weather, penetrations from energy efficiency programs, demand response programs. Also there's input as to what's expected, that there's going to be new demand response programs. So that is all built in on the load side.

And then as well as we have in our forecasts the Commission authorized, you know, energy efficiency mandated programs, the solar programs, demand response. So that the costs are also built into the forecast.

MR. MELLOR: How important are they? Do

they change the outcome in terms of your projected prices?

MR. SNOW: I would imagine on the load side it does. And when we're talking about a revenue requirement of, you know, $12, $13 billion, you know, $400 million public purpose -- I mean that's significant. It's increased a lot over time, but it's not, you know, it's not as big as -- procurement piece of our revenue requirement.

MR. HANSEN: For SDG&E it's also included in our revenue requirements. The requirements for and the efficiency. In the load and demand forecasting I would think that that also reflects assumptions for energy efficiency and demand response, for example.

And certainly it's had an effect on rates already in that SDG&E has, for residential, one of the lowest usage per customer amounts for energy use. Which equates to one of the higher usage per unit costs. So there's a relationship definitely. The more you save, if you can't save on fixed costs, it still results in higher average rates, even though it may result in lower bills.

MR. PRETTO: For Santa Clara the changes

in load growth is an interesting thought because our recent -- we've had some significant changes recently in load growth due to data centers. Some of whom could use some demand management, which we're trying to encourage with them.

But ultimately the changes in load growth are a factor in our load forecast, which in turn drives the cost forecast. Demand management expectations similar. So ultimately these filtered back to your revenue requirement. And from the revenue requirement you turn that around in a retail price forecast, and you're operating on a somewhat macro sense in terms of impacts ultimately on electricity demand.

So, they're factored in because they're in the revenue requirement. Ultimately their retail prices that you charge will reflect costs. And in that sense they are reflected.

MR. MELLOR: Nick.

MR. ZETTEL: For Redding load reductions from DSM and energy efficiency are included in the load forecast. And the firm that actually performs our forecasting model uses empirical data on the number of let's say rebates issued, dollars spent, the estimated impacts per rebate, in the

Redding area. And factors that into our load.

And then we also, in the resource planning arena, and load resource forecast, obviously don't have to procure or bill as much if it doesn't exist. And that's how Redding handles it.

And resource planning on a macro level, and then load forecasting on somewhat of a micro level.

MR. MELLOR: Rick or Antonio.

MR. ASLIN: So, for PG&E, yes, both the cost and benefits of customer energy efficiency and demand response are included in the forms that are filed.

MR. MELLOR: Big or little, percentagewise? How important is --

MR. ASLIN: Well, it's very important to California, that's for sure. And to our customers; it's certainly important to our management.

We included customer energy efficiency savings that were consistent with the targets, that were approved. And if you built in 5 percent demand response, which is also our target level, so built that all in.

If you're interested in what kind of spending we're doing on customer energy efficiency, it kind of ramps up from in 2005 I think it was around 200 million; and that ramps up to about 400 million by the time we get to 2016. So pretty substantial increase.

In terms of demand response I think we're estimating about $50 million a year in demand response expenditures. And so that's a pretty significant amount of spending there, as well.

But, of course, then you get the benefits by not having the load, and not having to build infrastructure to serve load.

MR. MELLOR: Commissioners.

ASSOCIATE MEMBER GEESMAN: I guess I would want to thank all of you for what I think has been an extremely informative discussion. I remain troubled by what we actually have in terms of a projected price forecast. But I think that we've gone through the natural gas side, and I've got a better understanding of that.

On the capital side I really do think that there's an inherent problem or deficiency with the way in which we've done it. I recognize the difficulty of moving beyond clearly identifiable projects into some other category.

But I think it ought to be the position of the utility industry and its regulators, in a state that has a very high propensity to under-invest in infrastructure, that we need to keep these capital budgets at a realistic level of investment.

And frankly, I think when you see trailing levels of capital investment in the out years, that, to me, sends a real red flag that that's something we ought to correct. That isn't something that this Commission or hopefully our colleagues at the PUC should embrace.

And frankly, I also believe, at least in the investor-owned portion of the industry, the returns on capital allowed the last several years and the trading levels of your stock are such that I think the real clear signal from state policy has been invest, invest, invest.

And if that message is not properly getting across, in a period as short as ten years from now, I think there's a problem that state policymakers need to recognize and attempt to turn around.

COMMISSIONER BYRON: I think, Commissioner, you make some excellent points. I'd also very much like to thank you for being here today to help us understand these issues a little more clearly and give us a chance to ask you some questions.

I'm still very concerned despite the best efforts to try and make these projections, these forecasts. It does paint a rather rosy picture for rates for the future here in California, based upon all the nationwide consultants and EIA's forecast for natural gas, and, of course, your revenue requirements and expected capital expenditures, as Commissioner Geesman pointed out.

And I'm a little bit concerned that as an energy commission we staple those results and put them out as a report. And it may be a little bit misleading.

I appreciate PG&E's looking at different scenarios, and I think that that's exactly the kind of thing that we need to be doing. And we're really only looking at the rosy scenario, to some extent, in terms of this report.

So, again, that doesn't detract in any

way from your efforts and your being here today. I appreciate that, thank you very much.

PRESIDING MEMBER PFANNENSTIEL: This is an important part of the whole IEPR process. And I think it's one that we perhaps haven't paid as much attention to in the past, but as you've heard from all of us today, we're concerned that this is as credible a building block as any of the others.

And I think that the two -- what I take away from this is that it looks like the gas price forecasts are while perhaps a consensus forecast, that still doesn't mean it's right. And we have reason to doubt that.

And then with the revenue requirements forecast, we have other concerns. And so we come away with a report that is accurate based on the information provided. And I think in everybody's own instance it does represent a good faith effort of building up. And yet, I don't think anybody's very comfortable with the overall results that we're working from.

I think that there's still an opportunity for each of the utilities and each of the participants to offer us thoughts or adjustments or alternative scenarios or ways of cautions on using these.

We have heard today from both parties who came to the podium, and invited participants, that it's important to get some base forecasts of retail prices that people will use. Because if we don't give them good ones, they're going to take what we have and use them. And they may use them incorrectly or inappropriately, and I don't think that does the state much good.

So, to the extent we can improve these numbers, even at this late date, even qualitatively, I think it's in all of our interests to do that.

I want to thank the individuals who are here on the panel today. I know that was not easy, and you know, you did a really good job of helping us understand this. So, thank you. And thank you to our moderator. Back to Mignon.

MS. MARKS: Thank you. I also would like to thank our speakers, Carl Pechman, Bob Logan and Greg Broeking for their help in helping organize this workshop and put on the quality information.

I would, in carrying on with your thoughts about continuing the dialogue, we are open for comments on the staff report and the numbers that are published in the staff report. We'd like to receive them, though, by July 13th, Friday the 13th, if possible.

And so please submit them to us, and to the docket; it's 06-IEP-1H. Thank you very much.

PRESIDING MEMBER PFANNENSTIEL: Are there public comment from people in the room here or on the phone?

No. Hearing none, we'll be adjourned. Thank you.

(Whereupon, at 11:56 a.m., the Committee workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Committee Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 17th day of July, 2007.